Turkey's Options to Control Energy Sector Air Pollution:
Emissions Outlook until 2025 for GHGs and Other Pollutants

By Guenter Conzelmann, Robin Bates, Vladimir Koritarov, Akihisa Mizuno, Emine Olgaç, Stratos Tavoulareas, and Keiichi Yoneyama[1]

As part of a comprehensive Energy and Environment Review of Turkey, sponsored by the World Bank's Energy Management Assistance Program (ESMAP) and Japan Staff and Consultant Trust Fund, a group of Turkish and U.S. analysts used the ENergy and Power Evaluation Program (ENPEP) to simulate the country's energy markets and develop long-term emissions forecasts for a variety of pollutants and scenarios. The projections extend to 2025 and include emissions trajectories for 26 pollutants, including greenhouse gases (GHGs), criteria pollutants, and air toxics. This paper presents the bottom-up energy market analysis for a reference case as well as a number of alternative scenarios that examine options to reduce Turkey's GHG emissions as well as emissions of PM, SO_2, and NO_X.

An important conclusion of the analysis for climate change policy is that each of the options applied individually does not have a major impact on GHG emissions. An effective national policy on climate change will have to rely on the aggressive application of a combination of options. An analysis of several policy scenarios aimed at lowering emissions of PM, SO_2, and NO_X demonstrates that improving Turkey's petroleum product quality could lead to noticeable cuts in sulphur emissions at a reasonable cost. Similarly, the introduction of European Union standards in the power industry would lead to substantial emissions reductions at relatively moderate costs.

Keywords: Turkey, GHG mitigation, pollution abatement, environmental policies, World Bank Energy and Environment Review

1. INTRODUCTION

Turkey's demand for energy and electricity is increasing rapidly. Since 1990, energy consumption has increased at an annual average rate of 4.3%. As would be expected, the rapid expansion of energy production and consumption has brought with it a wide range of environmental issues at the local, regional, and global levels. With respect to global environmental issues, Turkey's carbon dioxide (CO_2) emissions have grown along with its energy consumption. Emissions of CO_2 in 2000 were 211 million metric tons.

With GDP projected to grow at over 6% per year over the next 25 years, both the energy sector and the pollution associated with it are expected to increase substantially. This is expected to occur even if Turkey were to impose stricter controls on lignite and hard coal-fired power generation. All energy consuming sectors, that is, power, industrial, residential, and transportation, will contribute to this increased emissions burden.

Turkish Government authorities charged with managing the fundamental problem of fostering economic development while protecting the environment include the Ministry of Environment (MOE), the Ministry of Energy and Natural Resources (MENR), and the Ministry of Health. The World Bank, working with these agencies as well as the Turkish Electricity Generation & Transmission Company (TEAS), assessed the costs and benefits of various energy policy alternatives under a recent Energy and Environment Review (EER). As part of the EER, eight individual studies were conducted to analyze certain key energy technology issues and to fill in the gaps in data and technical information. The purpose of the analysis presented in this paper was to integrate information obtained in other EER tasks and provide Turkey's policy makers with an integrated systems analysis of the multiple options for addressing the various energy and environmental concerns.

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2. ANALYTICAL METHODOLOGY

The study was carried out by Argonne National Laboratory's Center for Energy, Environmental, and Economic Systems Analysis (CEEESA) in close collaboration and support by a team from MENR and TEAS. The analytical methodology is based on the ENergy and Power Evaluation Program (ENPEP), an integrated energy modeling system developed by Argonne. The Model for the Analysis of Energy Demand (MAED) was used for projection of energy demand, including electricity. The Wien Automatic System Planning Package (WASP) was used for electricity generation expansion planning. The ENPEP-BALANCE model projects future fossil and non-fossil energy flows in Turkey from energy extraction through end use across all sectors. ENPEP-BALANCE is a generalized equilibrium model that consists of a system of simultaneous linear and nonlinear relationships that specify the transformation of energy quantities and energy prices through the various stages of energy production, processing, and use. The model also calculates the environmental burdens, such as emissions of greenhouse gases and other pollutants. In addition, the VALORAGUA model was used to evaluate the operation of the hydro portion of the electric system.

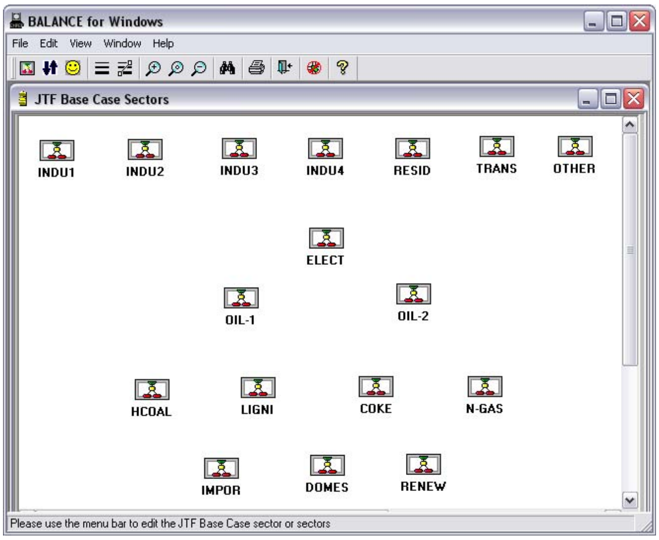

Figure 1: Turkish ENPEP Network

As central integrating module, ENPEP-BALANCE utilizes an energy network that was constructed to simulate the interactions among energy supply and demand sectors as shown in Figure 1. A more detailed network representation is given in the full report (Conzelmann and Koritarov, 2002). The network design for the individual sectors varies, mostly depending on data availability.

3. ENERGY SECTOR DEVELOPMENT SCENARIOS

A Reference Case was developed to compare alternative scenarios. Scenarios are divided into two main categories: (1) Greenhouse Gas (GHG) Reduction scenarios that analyze options in the form of technologies and policies that are primarily oriented toward the reduction of CO_2, methane (CH_4), and nitrous oxides (N_2O) and (2) Local Pollution Reduction scenarios that analyze several options mostly targeting the reduction of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X), and solid waste.

The GHG Reduction scenarios look at (1) technical efficiency improvements in existing power generating units, (2) clean coal technology for power generation, (3) constrained natural gas supply combined with the use of new sub-critical and super-critical coal-fired power stations (4) nuclear power, (5) demand-side management (DSM), (6) expanded use of cogeneration in the industrial sector, (7) expanded use of renewables for electricity generation, and (8) introduction of a carbon tax. For brevity, only scenarios 5, 6, and 7 are presented in this paper.

The Local Pollution Reduction scenarios analyze the impact of (1) petroleum product quality improvements and (2) the implementation of European Union (EU) Standards for the power and oil sectors.

4. MACROECONOMIC FORECASTS AND ENERGY DEMAND PROJECTIONS

The energy demand forecast by sector came from the latest available official forecast from MENR. As part of Task 1 under the Turkey EER, a review of the Turkish energy demand forecast was performed. The econometric analysis found that, although the growth rates were robust over a long period of time, there were no solid grounds for rejecting these forecasts in favor of lower figures.

The underlying annual population growth rate is 1.1% but declines from 1.41% for 1995–2005 to 0.8% for 2020–2025. The average GDP growth rate is 6.15% with higher rates at the beginning (7.74% during 1995–

2005) and lower rates toward the end (5.6% for 2020–2025). The sectoral contributions of agriculture, mining, and construction are projected to fall while those of energy, manufacturing, and services increase. Given the macroeconomic assumptions, total final energy consumption is projected to grow at an average rate of 5.9% per year, while electricity demand is projected to increase on average by 7.4% per year. Growth rates vary by sector with industry growing the fastest (7.6%) and agriculture and non-energy growing the slowest (3.9% and 3.0%). Growth rates are not constant and typically fall from the beginning to the end of the planning horizon.

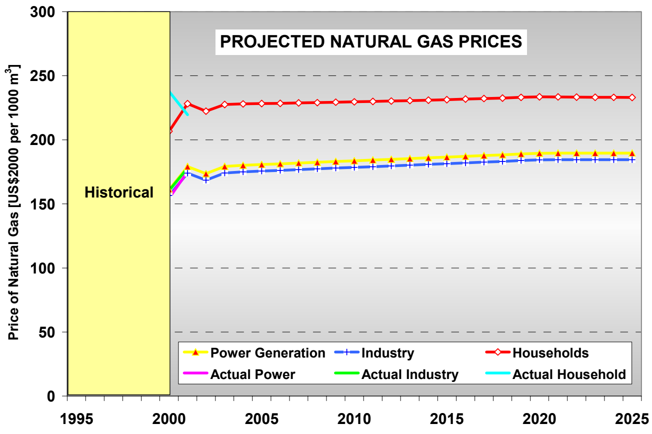

Figure 2: Projected Consumer Gas Prices

5. REFERENCE CASE RESULTS

5.1 Price Projections

Prices drive the consumption of individual fuels as they compete for market share in the various end-use sectors. BALANCE is set up and calibrated to project consumer prices based on current and projected resource costs (crude oil, coal, and natural gas imports), conversion costs, and taxes and subsidies. For example, Figure 2 shows projected gas prices by consumer group.

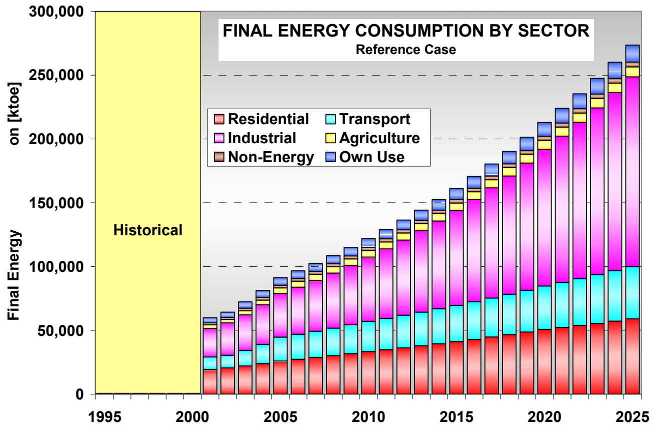

Figure 3: Reference Case Final Energy Consumption by Sector

5.2 Final Energy Consumption

Based on the demand forecast from MAED, total final energy consumption grows at an average rate of 5.9% per year from 65.5 million tons of oil equivalent (mtoe) in 2000 to 273.5 mtoe in 2025. Average annual growth rates vary by sector, with industry having the highest rate at 7.6%, followed by the transportation sector with 5.0%. During the years 2000–2025, industrial consumption increases from 23.9 to 148.9 mtoe increasing its share from 36% to 54% (see Figure 3).

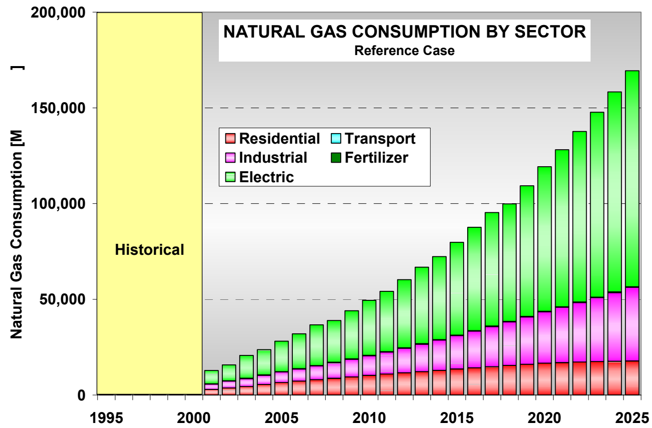

Figure 4: Reference Case Gas Consumption by Sector

In terms of final energy by fuel, between 2000 and 2025 hard coal/coke increase their share slightly from 13 to 18%, lignite holds steady at 6%, electricity grows from 17 to 24%, oil products decline from 42 to 29% and natural gas increases from 7 to 17%. The model also projects fuel mixes for each of the consumer groups or demand sectors.

5.3 Natural Gas Consumption

Total natural gas consumption is projected to increase at an annual rate of 9.6% from 15.0 to 169.4 billion m^3 (bcm) during 2000–2025. Power sector gas demand is one of the main drivers for this projected growth and will account for 112.8 bcm, or 67% of total gas consumption in 2025 (up from 9.3 bcm in 2000). Industrial demand is the fastest growing market segment (11.5% annually) with gas expanding from 2.5 to 38.4 bcm during 2000–2025 and eventually accounting for 23% of total gas consumption (Figure 4).

Projected natural gas consumption levels for the industrial, residential, and electric power sectors are compared with the latest forecasts by the Turkish gas company (BOTAS). For the industrial sector, ENPEP is projecting a more delayed market adoption, yet by 2015, the ENPEP projection is within 9% of the BOTAS forecast. A somewhat different picture emerges for the residential sector, where up to 2012, projected ENPEP gas consumption is somewhat lower than the BOTAS values (within 1% by 2012), but then rises above the BOTAS values. For the electric sector, ENPEP tends to project lower values until 2008 and then higher values due to the aggressive gas-based power system expansion.

5.4 Electric Power Generation

New capacity additions are projected to total about 108 GW by 2025. Results indicate that the majority of the load growth is met with natural gas-fired generation (Figure 5). By 2025, gas-fired units represent 67% (93 GW) of the installed generating capacity and account for 77% of total generation (588 of 768 TWh).

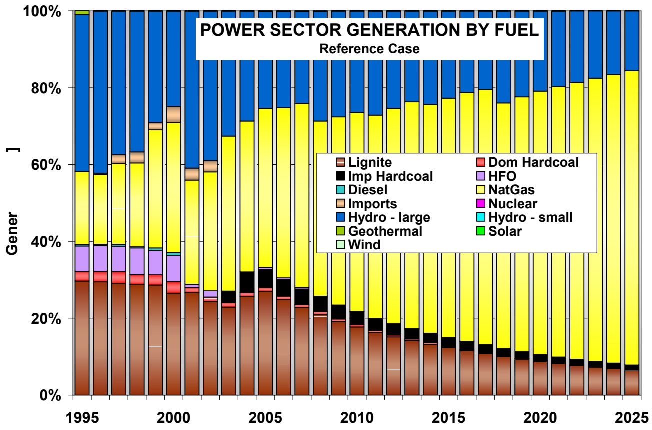

Figure 5: Reference Case Projected Generation Mix

5.5 Primary Energy Supply

Primary energy supply is projected to increase from 64.5 mtoe (1995) to 332.0 mtoe (2025). Crude oil imports remain constant at 33.0 mtoe after 2004 when the domestic refineries are forecast to reach their existing processing capacity, resulting in a drop in crude oil share from 44% to 10% of total supplies. Once the refining capacity is reached, net imports of refined products quickly grow from 2.6 to 52.3 mtoe (2000–2025), accounting for about 16% of total supplies by 2025. Natural gas quickly increases its share from 10% (6.3 mtoe) in 1995 to 42% (139.8 mtoe) of total supplies in 2025 (Figure 6). Although renewables double during 2000–2025, their share decreases from 14% in 2000 to 7% in 2025.

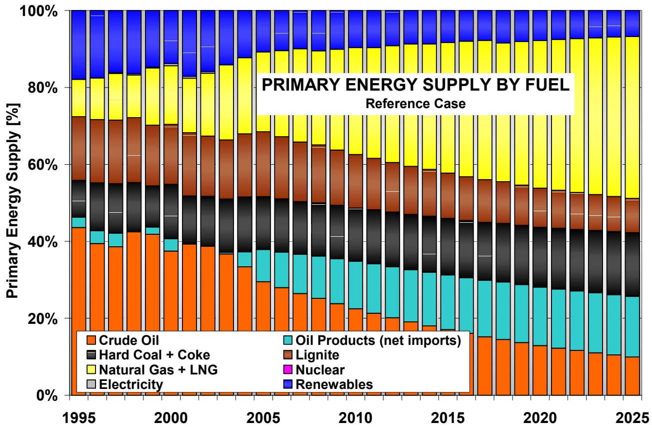

Figure 6: Reference Case Projected Primary Energy Supply Mix

5.6 Energy Import Bill

Overall energy imports increase substantially from 37.1 mtoe (1995) to 275.2 mtoe (2025) and will bring Turkey's energy import dependency to 83% by the end of the study period. While in 1995, crude oil accounted for the majority of imports (67%), natural gas imports are slated to take this position with 51% by 2025. Turkey's total net energy import bill under the Reference Case is estimated to have a net present value (NPV) for the entire study period of \$155.5 billion with the total economic system cost of delivered energy estimated at \$372.6 billion (NPV).

5.7 Projected Emissions

For this analysis, the ENPEP model was configured to develop emission trajectories for 26 pollutants, including the major GHGs, pollutants of local/regional concern (PM, SO_2, NO_X, etc), as well as air toxics (e.g., heavy metals). The complete results are documented in Conzelmann and Koritarov (2002). Please contact the authors for the complete emissions results.

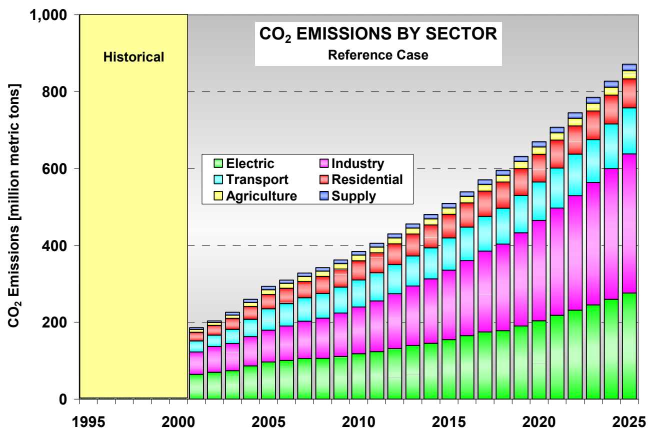

Figure 7: Reference Case CO_2 Emissions

The model projects total CO_2 emissions to increase at an average rate of 5.8%/yr and reach 871 million t/yr by 2025 (Figure 7). The industrial contribution changes the most noticeably, rising from 31 to 42% driven by the high growth in industrial final energy as well as the continued reliance on solid and liquid fuels in this sector. Total national SO_2 emissions reach a low point in 2003 with 1.83 million t/yr, but then more than double to 3.85 million t/yr by 2025. The majority of the emissions growth can be attributed to an increase in industrial solid fuel and fuel oil combustion and an associated rise in SO_2 emissions from 566 to 2,411 kt/yr during 2000–2025. By the end of the study period, industry is expected to be responsible for 63% of Turkey's SO_2 emissions. The increasing significance of the manufacturing sector goes hand in hand with a declining importance of the power sector. In 2000, electricity generation accounted for 55% of national sulphur emissions, but this share will be down to 24% by 2025. This is in large part because coal generation stays more or less constant while several new sulphur controls are already commissioned and expected to come on-line in the very near term.

6. GHG SCENARIO RESULTS

6.1 Cogeneration Scenario

The Cogeneration Scenario evaluates the economic and environmental impacts of more extensive use of cogeneration facilities in Turkish industrial plants. Results show that the projected growth in cogeneration essentially leads to a more moderate power sector natural gas expansion as well as a drop in gas-fired power generation. That is, a total of 23.3 GW (26%) of power sector combined cycle gas turbines (CCGTs) are avoided by cogeneration. Cogeneration reduces power sector gas-fired generation by as much as 26% by 2025.

While power sector natural gas consumption is expected to decline by 29.7 bcm (26%), industrial gas consumption is projected to grow substantially (53% over the Reference Case). Industry in this scenario accounts for 43% of total gas consumption (2025) as compared to 23% under the Reference Case. Natural gas is substituted for hard coal and coke, lignite, and oil products. The net effect of the growth in industrial gas consumption and the drop in power sector gas consumption is an overall increase by 9.4 bcm (5.5%) from 169.4 to 178.8 bcm by 2025.

The supply shows the benefits of cogeneration as the higher overall efficiency of cogeneration leads to a cut in total energy supplies by 16.6 mtoe (5%) by 2025 (see Figure 8). Despite the net increase in gas consumption, net energy imports are substantially reduced because of the drop in imported refined products and hard coal/coke. Cogeneration saves \$916 million in imports (NPV) while the incremental cost is negative, that is, a NPV of -\$63 million.

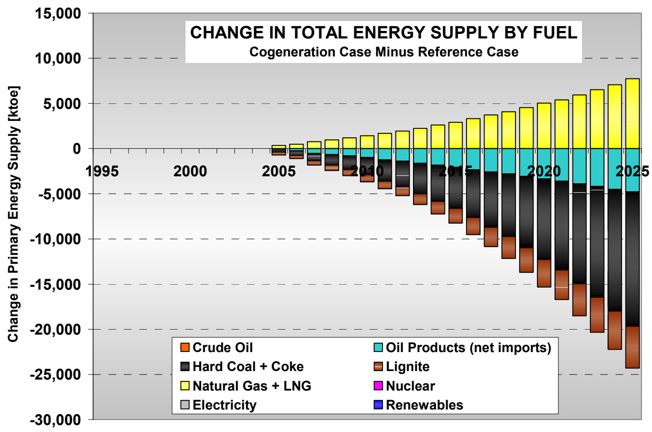

Figure 8: Cogeneration Scenario Change in Primary Energy Supply

As shown in Figure 9, the increased cogeneration program reduces power sector CO_2 emissions in 2025 by 54 mt/yr (20%) as a result of the drop in load and the corresponding decline in generation and fuel consumption levels. Industrial emissions drop by about 17.7 mt/y (4.9%). The overall fuel savings and the lower capital investment requirements in the power sector more than offset the costs involved in expanding industrial cogeneration. Cumulative emission reductions are substantial at 592 mt of CO_2 (4.8%). With the negative incremental cost, the cogeneration scenario is a cost-effective, "win-win" situation at -0.1 \$/ton of CO_2.

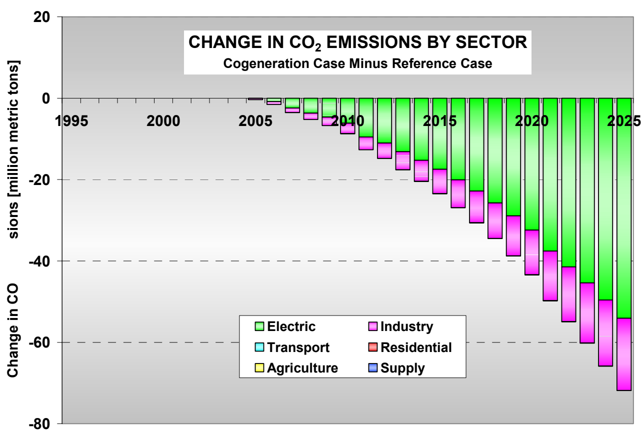

Figure 9: Cogeneration Scenario Change in CO_2 Emissions

Cogeneration has substantial ancillary benefits in the form of cumulative reductions of PM, SO_2, and NO_X.

Cumulative SO_2 emission reductions total about 6.07 million tons (9.0%), closely followed by an 8.6% reduction (1.86 million tons) in cumulative PM emissions.

6.2 Renewables Scenario

The Renewables Scenario is designed to analyze the economic and environmental impact of more extensive use of wind energy and mini-hydroelectric plants. Solar photovoltaic (PV) installations were initially included in the first computer simulations but then dropped as the results showed they were not cost-effective in Turkey for grid supply. The more aggressive renewables program starts in 2005.

Results show that under the Renewables Scenario, 7,250 MW of natural gas-fired capacity is replaced by 19,250 MW of wind and 1,107 MW of small hydro during 2000–2025. By 2025, all renewables combined (including large hydro) amount to more than 54 GW or 35% of installed capacity. The additional generation from renewables quickly increases to 53.8 TWh (7% of total) by 2025 and essentially replaces CCGT generation with only minor changes in the dispatch of the other fossil fuel units. Combined with large hydro and geothermal, renewables generate 173.6 TWh (22.6%) of electricity by 2025.

CO_2 emissions from power generation are reduced by 16.7 mt/yr (5.9%) by 2025 as natural gas-fired generation is replaced by wind and small hydro which limits the emission reduction potential of renewables. Renewables can lower net energy imports by \$1.49 billion (NPV) at an incremental cost of \$228.6 million. This leads to a cost-effectiveness of \$1.3 per ton CO_2 or \$4.6 per metric ton of carbon equivalent (MTCE). Although the total discounted economic system cost increases relative to the Reference Case, wind energy and mini-hydro appear to be cost-effective options for the mitigation of CO_2 and GHGs. Ancillary benefits in form of reduced PM, SO_2, and NO_X emissions are very minor though (0.4% at the most).

6.3 DSM Scenario

The purpose of the demand-side management scenario is to look at the potential of DSM and energy conservation measures to reduce energy consumption and national GHG emissions and to measure the impacts on total energy system costs.

Results show that by 2025, total final energy consumption drops by 44.7 mtoe, or 16.3%, from 273.6 to 228.9 mtoe (Figure 10). The largest declines are experienced by hard coal and coke (24.5%), lignite (24.3%), and natural gas (24.2%). Electricity consumption falls by 19%, while oil products are reduced by 6.2%.

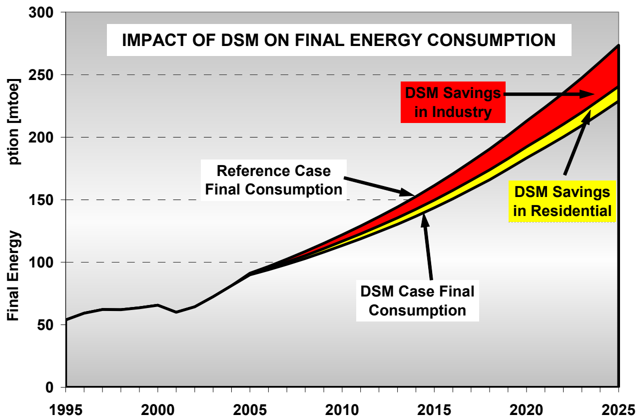

Figure 10: DSM Scenario Final Energy Consumption

Emission reductions in the DSM scenario are significant and take place in the industrial, residential, and power sectors. DSM reduces national CO_2 emissions in 2025 by 160 million tons per year or by 18.3% (Figure 11). Sectoral reductions are as follows:

- 83.3 mt/yr or 23.0% in industry,
- 22.5 mt/yr or 29.8% in households, and
- 54.1 mt/yr or 19.6% in the power sector.

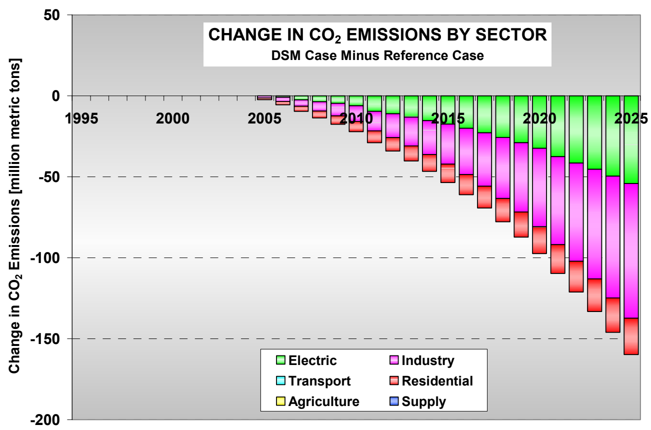

Figure 11: DSM Scenario Change in CO_2 Emissions

The incremental cost is negative, that is, a NPV of -\$23.05 billion. This appears to make DSM a very attractive option. The very high cost savings come with the highest cumulative emissions reductions of all scenarios, that is 1.34 billion tons of CO_2 (10.8% reduction), 5.32 million tons of SO_2 (7.9% reduction), 1.77 million tons of NO_X (6.5% reduction), and 1.52 million tons of PM (7.0% reduction). Reasons why this option appears so attractive include a possible underestimation of the cost of industrial DSM efforts and the fact that an optimistic DSM target of 20% was used for the household sector at no cost.

7. LOCAL POLLUTION SCENARIO RESULTS

7.1 Petroleum Product Quality Scenario

The Petroleum Product Quality Scenario is designed to analyze the environmental effectiveness of reducing the sulphur content of fuel oil starting in 2003. The analysis focuses on heavy and light fuel oil used by households, industry, the utility sector, and some minor amounts in the supply and transport sectors. Reducing the fuel oil sulphur content cuts Turkey's SO_2 emissions in 2003 by 241 kt/yr (13.1%). By 2025, the cuts are even larger with 19.9% (from 3.85 to 3.08 mt/yr). The majority of emissions reductions (81%) are projected for the industrial sector (Figure 12). This reduces industrial SO_2 emissions by 26% from 2.41 to 1.79 mt/yr.

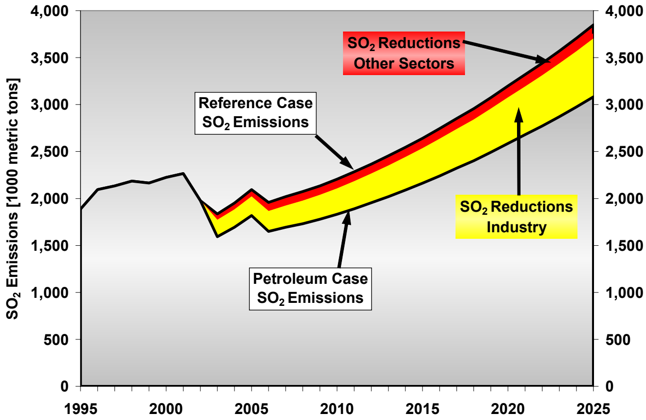

Figure 12: Petroleum Product Quality Scenario SO_2 Emissions

The incremental cost is $718 million (NPV). Given the large total cumulative emissions reductions of 10.95 million tons of SO_2 (a cut of 16.2%), the scenario appears to be an attractive sulphur control option with a cost-effectiveness of $252/ton (discounted). Ancillary benefits are negligible.

7.2 EU Standards Power-Only Scenario

The EU Standards Power-Only Scenario analyzes the effects of implementing the new EU Standards for power stations. Under the scenario, existing lignite and hard-coal generating units are modified to reflect installation of new environmental control equipment or upgrade of existing equipment. Retrofits are conducted in 2 stages:

- 2009 to meet EU-2001 standards on PM and SO_2
- 2015 to meet EU-2001 standards on NO_X

In addition, all new generating stations are required to meet the EU standards.

Based on unit-level compliance information, CEEESA staff estimated the investment requirements, impacts on the operation and maintenance (O&M) costs of the units/plants, and the effect on unit-level heat rates. The total capital investment requirements to comply with all EU standards for PM, SO_2, and NO_X are estimated at $375.3 million (NPV).

Adding the cost of pollution control and the change in heat rates of the existing lignite and hard coal-fired units leads to a shift in the dispatch order where part of the lignite-fired and domestic hard coal-fired generation is substituted for gas-fired CCGT generation.

As given in Figure 13, model results show a cut in power sector SO_2 emissions in 2025 of 803 kt/yr (85%). A similarly large reduction (77%) is observed for PM emissions. On a national scale, SO_2 emissions in 2025 drop by 21%. The lower power sector emissions cause the industrial contribution to be more prominent, that is, industry will account for 79% of national SO_2 emission by 2025.

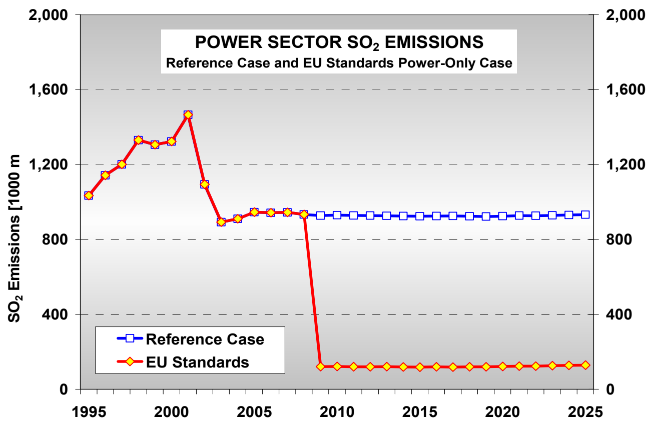

Figure 13: EU Standards Power-Only Scenario Power Sector SO_2 Emissions

The NO_X standards will cut power sector emissions by 61.3 kt/yr (21%) by 2025. However, the impact on national emissions is minor, that is, a 3.7% reduction.

The incremental cost is $637 million (NPV), but given the substantial total cumulative emissions reductions of 13.7 million tons of SO_2 (20.2%), the scenario appears to be an attractive sulphur control option with a cost-effectiveness of $211/ton (discounted). Ancillary benefits in terms of GHG reductions are negligible.

7.3 EU Standards Power and Oil Scenario

This scenario is built on the previous scenario. In addition to implementing the power sector-related EU standards, this scenario also improves the quality of petroleum products in line with EU requirements, as under the Petroleum Product Quality Scenario.

The impact on Turkey's total SO_2 emissions is substantial, that is, a 41% reduction in 2025 national emissions compared to the Reference Case. Improving the petroleum product quality contributes heavily to these reductions: 49% of the emission cuts in 2025 are attributable to the sulphur reduction in fuel oil.

The incremental cost is $1.365 billion (NPV). Given the substantial total cumulative emissions reductions of 24.6 million tons of SO_2 (a 6.4% cut), the scenario turns out to be an attractive sulphur control option with a cost-effectiveness of $231/ton (discounted). Ancillary benefits in terms of GHG reductions are negligible.

8. CONCLUSIONS

8.1 Reference Case

The Reference Case highlights the advantages of natural gas for the development of Turkey's energy supply, especially in the power sector. Given the underlying price projections of the Reference Case, more extensive gas use than at present appears to be the least-cost way of meeting growing electricity demand. At the same time, emissions of most pollutants are moderated and grow at rates below the growth of final energy demand. The benefits of a substantial shift from using domestic coal to reliance on imported natural gas will, however, have to be weighed against increased exposure to potential gas price volatility, particularly given recent natural gas price movements and security of supply concerns.

Model runs for a Reference Case variation that constrained the total available gas imports tried to quantify the benefits of natural gas against a greater use of coal and lignite. The results show that although gas imports and the import bill are higher under the Reference Case (by 23% and 1.5% respectively) than under this variation, the economic cost of energy supply is lower and so are all emissions, hence natural gas appears to be a "win-win" option, given the underlying price projections. Additional Reference Case variations show that if gas utilization in the electricity sector is to be restricted, it is better to rely more on super-critical rather than sub-critical technology for coal-fired power generation.

Results for a low-GDP variation of the Reference Case show the sensitivity of national emissions to the assumed economic growth. Under the low-GDP scenario, national CO_2 emissions in 2025 are about 43% lower than under the Reference Case. The impact on other pollutants is comparable, that is, NO_X lower by 40%, PM 39%, and SO_2 32%.

8.2 GHG Scenarios

Based on results from the GHG scenarios, the following conclusions can be drawn in relation to formulating a national policy on climate change.

As Figure 14, Figure 15, and Table 1 show, DSM, cogeneration in industry, and improved technical efficiency in the power sector are clearly essential ingredients of future climate change policies. They are "win-win" options compared to the Reference Case. Under all these scenarios, the economic cost of energy supply and the cost of energy imports will be lower as will emissions of GHGs. In addition, there are substantial ancillary benefits involved in terms of PM, SO_2, NO_X, and other pollutants, particularly with regard to DSM and cogeneration. However, it must be acknowledged that the scope for more reliance on cogeneration in industry and improved technical efficiency in the power sector is intrinsically restricted. Scenario results suggest that less than 5% and 1% reduction in GHG emissions, respectively, can be accomplished during 2000–2025.

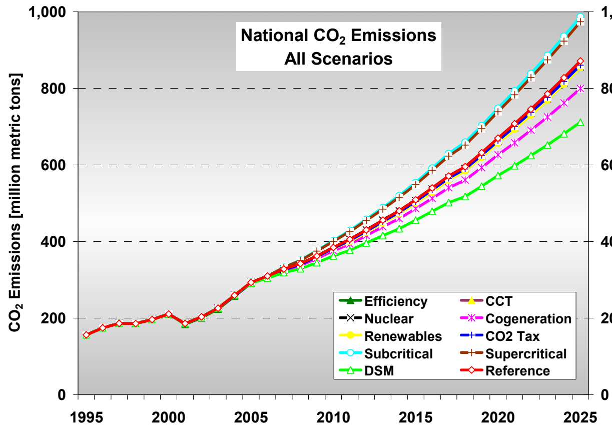

Figure 14: CO_2 Projection to 2025 All Scenarios

Also, the implementation costs for DSM may be underestimated while the environmental impact is the greatest in terms of projected emission reduction. The reduction in GHG emissions exceeds 10% during 2000–2025 and the potential may be even more, as the analysis only concentrated on the residential and industrial sector but excluded the transportation sector for lack of country-specific information.

Renewables have a role to play in GHG reduction policy, but development of renewables will need to be selective. Mini-hydro and windmills are the most promising and offer an attractive cost for the reduction of GHG at an estimated \$1.3/ton of undiscounted CO_2 and \$4.6/ton of undiscounted carbon equivalent. Solar PV installations appear to be unattractive on cost grounds except perhaps for particular applications, such as off-grid supply or in low-temperature heating applications. The scope for mini-hydro and windmills is limited and scenario results suggest that total abatement of GHG emissions would be less than 2% during 2000–2025.

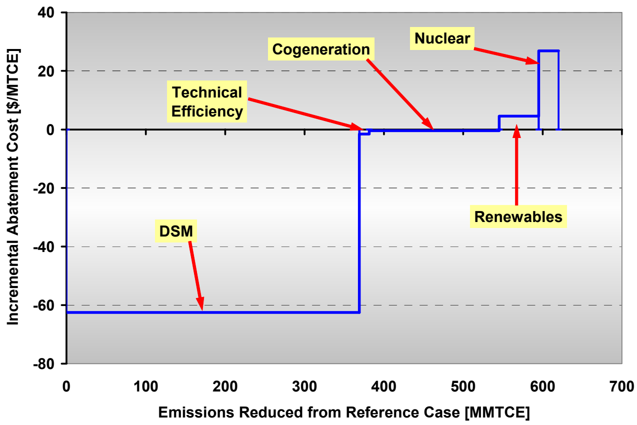

Figure 15: GHG Abatement Cost Curve

Each of the options applied individually does not have a major impact on GHG emissions: an effective national policy on climate change will have to rely on the aggressive application of a combination of options, e.g., DSM, cogeneration in industry, improved technical efficiency in the power sector, greater natural gas utilization, and investment in mini-hydro plants and windmills.

Scenario	Incremental Cost (million \$)	Change in Net Energy Imports (million \$)	Cumulative MMTCE Reductions (million tons)	MTCE Cost Effectiveness (\$/MTCE)
DSM	-23,054.2	-9,027.4	369.03	-62.5
Cogeneration	-63.0	-915.8	163.78	-0.4
Renewables	228.6	-1,493.4	49.75	4.6
MMTCE = million metric tons of carbon equivalent (includes CO_2, CH_4, N_2O); MTCE = metric ton of carbon equivalent				

Table 1: Summary of GHG Scenario Results

8.3 Local Pollution Scenarios

Based on results from the Local Pollution Scenarios, the following conclusions can be drawn in relation to formulating national policies aimed at improving local air quality. As in the case of GHG reduction policies, any strategy to control local pollution should consider the following (see Table 2 and Figure 16):

Improving the petroleum product quality would cut sulphur emissions by more than 16% during 2000–2025 at a cost of \$252/ton (discounted). The introduction of EU Standards and the improvement of petroleum product quality would be cost-effective options to reduce emissions of sulphur. EU standards would result in sulphur emissions 36% lower than under the Reference Case during 2000–2025. The cost of abatement is estimated to be about \$231/ton (discounted), and there would also be moderately lower emissions of PM and NO_X.

Scenario	Incremental Cost (million $)	Change in Net Energy Imports (million $)	Cumulative SO_2 Reductions (million tons)	SO_2 Cost Effectiveness ($/ton SO_2)
EU Standards Power-Only	637.2	79.8	3.01	211
EU Standards Power + Oil	1,355.1	32.2	5.86	231
Petroleum Product Quality	717.9	0	2.85	252

Table 2: Summary of Local Pollution Scenario Results

DSM, cogeneration in industry, and improved technical efficiency in the power sector can all contribute to local pollution control because the economic cost of energy supply and the cost of energy imports will be lower as well as emissions of PM, SO_2, NO_X, and ash. In contrast with GHG reduction policies, windmills and mini-hydro showed little promise for local pollution reduction policy relative to the Reference Case, because they had a negligible or no impact on PM, ash, NO_X, and SO_2. It should be noted, though, that the results are greatly influenced by comparison with the preponderance of natural gas in the Reference Case.

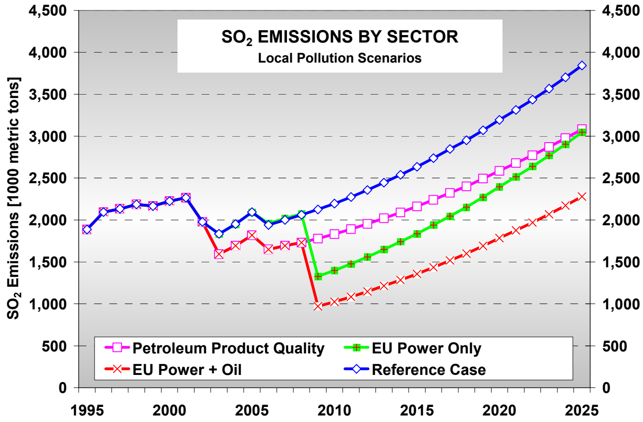

Figure 16: Summary of Local Pollution Scenario Results

As with the design of policies for GHG mitigation, it is clear that no one single policy option will have a major impact on all emissions causing local pollution. An effective national policy for the reduction of local pollution will have to rely on the application of a mix of options, e.g. DSM, cogeneration in industry, improved technical efficiency in the power sector, greater natural gas utilization, and tighter emissions standards.

REFERENCES

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